Flowing ENERGY

NIGHT AND DAY | *Always flowing.*

ANNUAL 2003 REPORT

Flowing Energy Corporation is a junior oil and natural gas explorer and producer based in Calgary, Alberta that has achieved rapid growth through the development and exploitation of low-risk, shallow-depth prospects at two core areas in eastern Alberta.

Flowing exited 2003 with productive capability of 3,200 boe per day, an increase of 1,027 percent from year-end 2002. In 2004, Flowing is exploring on its third core area and is prospecting for additional core areas.

Flowing is a publicly-traded company listed on the Toronto Stock Exchange (TSX) under the symbol FLO. At December 31, 2003 there were 38,970,186 common shares issued and outstanding.

Always flowing.

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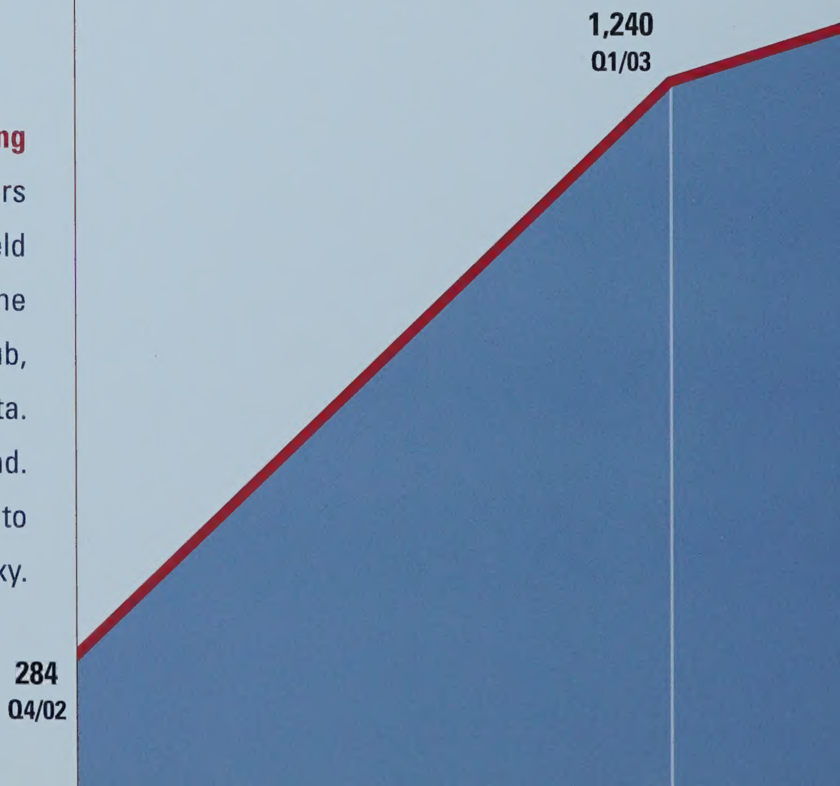
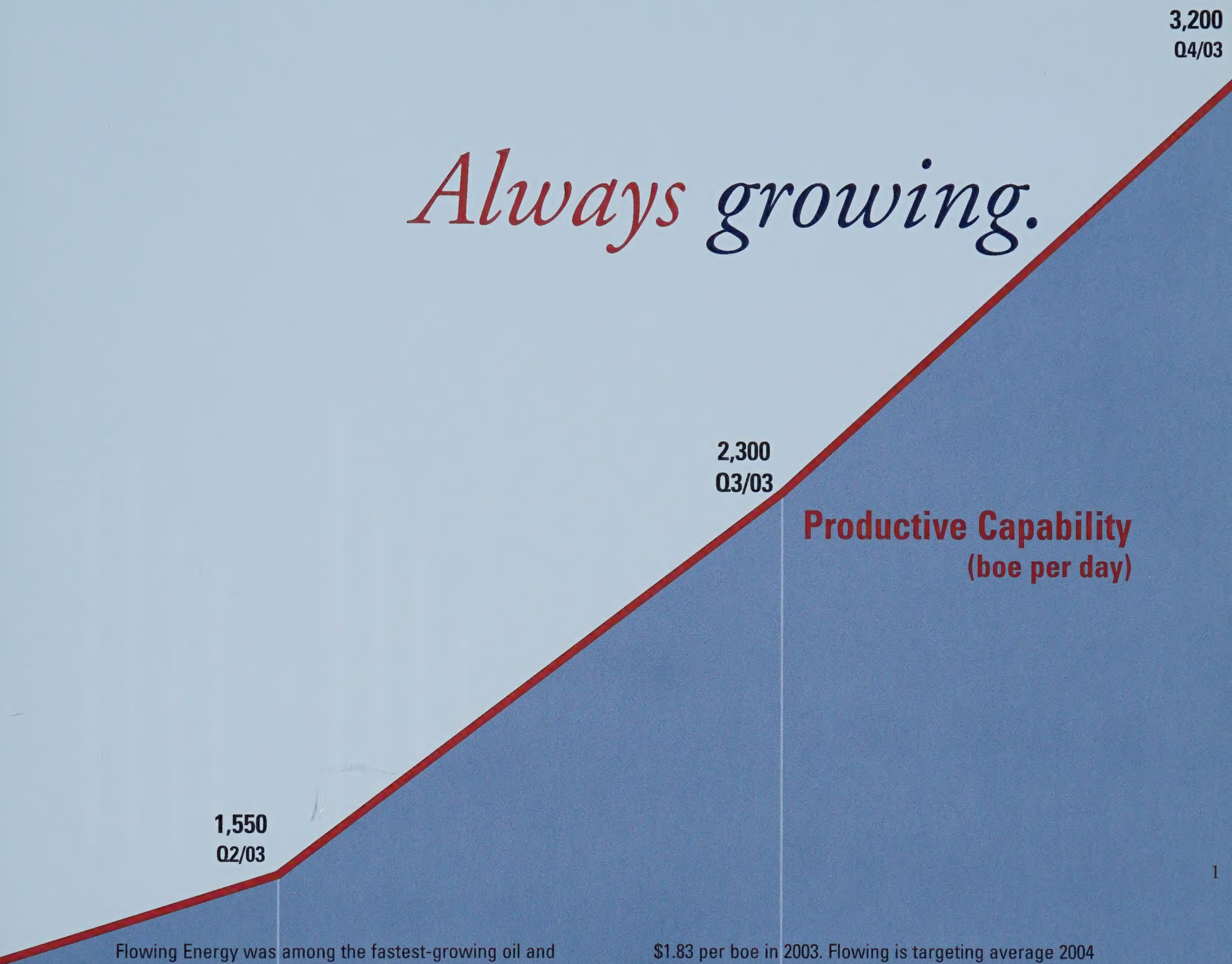
Annual General Meeting

The annual general meeting of shareholders of Flowing Energy Corporation will be held at 10:00 a.m. on May 7, 2004 in the Viking Room of the Calgary Petroleum Club, at 319-5th Avenue S.W., Calgary, Alberta. Shareholders are encouraged to attend. Those unable to attend are encouraged to complete and mail their form of proxy.



Always growing.



Flowing Energy was among the fastest-growing oil and natural gas companies in the Canadian energy industry in 2003. Flowing's average crude oil production grew by 940 percent and natural gas production grew by 1,155 percent for combined average volumes of 1,384 boe per day.

Growth was achieved entirely through the drill bit at the Corporation's two core areas, Wildmere and Monitor. With 111 (108.4 net) wells drilled or recompleted in 2003 – up from nine (7.6 net) wells in 2002 – net additions of 11.1 million boe of proved plus probable reserves were added for year-over-year reserves growth of 760 percent.

Flowing's volume growth was accompanied by improved unit efficiencies. Operating costs declined from $13.32 per boe of production in 2002 to $5.81 per boe in 2003. General and administrative costs fell from $13.81 per boe in 2002 to $1.83 per boe in 2003. Flowing is targeting average 2004 operating costs of under $7 per boe.

Shareholder value also grew during 2003. Flowing's share price appreciated from $0.92 at December 31, 2002 to $2.61 at December 31, 2003 while market capitalization increased from $18.8 million to $101.7 million during the same period.

The Corporation's strategic plans for 2004 include portfolio diversification with a strong natural gas focus. New natural gas exploration will commence in southwest Saskatchewan and Ponoka. Flowing will continue exploitation of existing opportunities at Wildmere and Monitor.

Flowing intends to grow production by over 200 percent to an average of over 4,400 boe per day for 2004.

Highlights

Drilling

Flowing drilled 111 wells with a success rate of 98 percent. Flowing was 10-for-10 in its Colony natural gas program at Wildmere, and drilled 71 successful vertical and horizontal wells on 40-acre spacing in its Lloydminster heavy oil play at Wildmere.

Production

Year-end production consisted of 2,450 barrels per day of crude oil (average 12 degrees API) and 4.5 million cubic feet per day of natural gas, for a natural gas weighting of 23.4 percent. December 2003 productive capability was 3,200 boe per day compared to 284 boe per day at December 2002.

Reserves

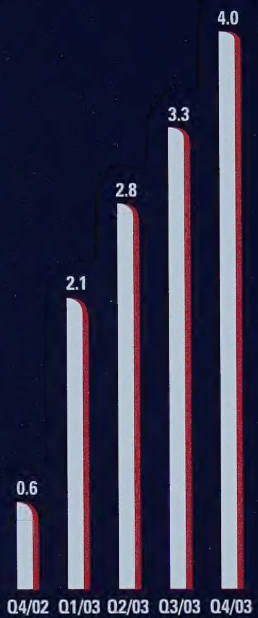
Proved plus probable reserves totalled 12.59 million boe at December 31, compared to 1.46 million boe one year earlier. Flowing's reserves were independently evaluated and are reported under the heightened standards of National Instrument 51-101.

Cost efficiency

Flowing continued to be an "efficient finder" as well as a profitable producer of oil and natural gas. With an average netback of $18.37 per boe of production and an average finding and development cost of $5.90 per boe of new reserves, Flowing had a recycle ratio of 3.1 times, one of the best in the Canadian oil and natural gas sector.

Profitability

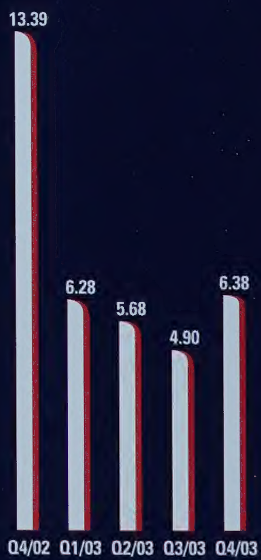
Cash flow was $8.1 million ($0.296 per share), compared to negative cash flow of $0.2 million ($0.012 per share) in 2002. Net earnings were $2.8 million ($0.103 per share), compared to a loss of $0.5 million ($0.031 per share) in 2002.



Revenues
($ millions)

Cash Flow
($ millions)

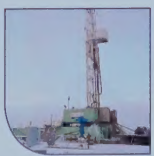
Productive Capability
(boe per day)

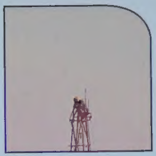


Operating Costs
($ per boe)

Always delivering.

For the year ended December 31	2003	2002	% Change
Operating			
Production			
Barrels of oil equivalent production (boe per day @ 6:1)	1,384.1	122.0	1,035
Crude oil and NGLs (bbls per day)	733.5	70.0	948
Natural gas (mcf per day)	3,904.0	311.0	1,155
Prices			
Barrels of oil equivalent production (boe per day @ 6:1)	$ 29.62	$ 27.82	6
Crude oil and NGLs ($/bbl)	$ 22.00	$ 30.36	(28)
Natural gas ($/mcf)	$ 6.37	$ 4.08	56
Field netback ($ per boe)	$ 18.37	$ 11.04	69
Operating cost ($ per boe)	$ 5.81	$ 13.32	(56)
Proved plus probable reserves (mmboe @ 6:1)	12.59	1.46	760
Wells drilled or recompleted			
Gross	111.0	9.0	1,133
Net	108.4	7.6	1,326
Undeveloped land (acres)			
Gross	41,721	28,031	49
Net	33,569	14,746	128
Financial			
Petroleum and natural gas revenue, net of royalties	$ 12,213,936	$ 1,084,691	1,026
Cash flow from operations	$ 8,136,788	$ (179,627)	4,630
Per share – basic	$ 0.296	$ (0.012)	–
– diluted	$ 0.277	$ (0.012)	–
Net earnings (loss)	$ 2,824,722	$ (471,652)	699
Per share – basic	$ 0.103	$ (0.031)	–
– diluted	$ 0.096	$ (0.031)	–
Working capital deficiency	$ 14,457,461	$ 281,543	5,035
Capital expenditures	$ 55,743,824	$ 4,852,258	1,049
Total assets	$ 64,095,591	$ 7,595,715	745
Long-term debt	$ 2,562,038	$ 500,000	412
Market capitalization	$ 101,712,200	$ 18,795,900	441
Shares			
Weighted average – basic	27,476,799	15,128,324	82
– diluted	29,398,822	15,128,324	94
Outstanding	38,970,186	20,430,344	91





President's Letter

Flowing delivered possibly the fastest percentage growth of any Canadian oil and natural gas producer in 2003. The Corporation met or exceeded most internal targets for production, reserves, cost efficiencies and profitability.

The average production rate of 1,384 boe per day was an impressive increase of 1,035 percent from the prior year. All of our growth came through the drill bit; we made no acquisitions of producing properties.

Our results confirm the soundness of the Corporation's business plan to grow through internal development of low-risk, shallow-depth oil and natural gas opportunities at two core areas in eastern Alberta. Flowing's fast and profitable growth is a testament to the performance and dedication of the Corporation's team of experienced technical, financial and field management personnel.

Major activities in 2003

Flowing budgeted on a quarterly basis and, as results exceeded expectations, repeatedly expanded capital spending and drilling. Capital expenditures totalled $55.7 million, funding 108.4 net wells.

Our innovative approach to developing the Lloydminster pool at Wildmere proved everything we hoped and more. Flowing's use of one vertical plus four to eight horizontal wells per drilling pad, with one pad per quarter section, delivered exponential growth in volumes and reserves. We completed 11 pads and pursued Colony gas potential, with 10 successful wells. The repeatable design yielded

Left to right: Paul J. Poscente, Vice President, Exploration; David G. Mallory, Chief Financial Officer and Corporate Secretary; Robert D. Bowman, President and Chief Executive Officer.



efficiencies including self-generated electricity, reduced surface acquisition costs and faster drilling times. We also doubled our land base at Wildmere with a view to exploring beyond our Lloydminster pool in the years to come. It is worth recalling that Wildmere, which was producing 175 boe per day at year-end 2002, began as a half section that the Corporation had held previously with a farm-in in March 2002 on another one-half section of land.

Development drilling at Monitor focused on Viking formation natural gas prospects, with 15 wells completed in 2003. Exploration wells targeted light oil or gas in several Mannville zones as well as the shallow Belly River formation. Flowing was active at Crown sales and concluded several farm-ins in this tightly held area.

Efficient growth

Equally important to achieving growth is cost-efficiency. By operating our plays and assembling high working interests, our business plan aimed to make Flowing an "efficient finder" and a low-cost operator.

At $5.90 per boe of new reserves added in 2003, Flowing's average finding and development (F&D) cost was best-quartile industry performance. Wildmere is yielding prolific reserves. On top of that, Flowing works hard to get the most out of its investments. The multi-horizontal-well development scheme reduces surface lease and infrastructure needs. Process improvements at mid-year cut drilling times significantly. Ongoing seismic imaging plus our record of 81 well penetrations reduces capital risks.

Flowing's unit operating costs fell from $13.32 per boe in 2002 to $5.81 per boe in 2003. Operating costs are a function of good design and meticulous execution. For example, Flowing's decision to self-generate power at Wildmere using a small proportion of our Colony natural gas production reduced operating costs by $2-$3 per boe of production. Good design is complemented by never-ending attention to detail by Flowing's field personnel. Low overhead and intense focus can enable a small producer to outperform larger ones, and this is in fact happening at Wildmere. The Corporation had excellent results in production gains in 2003 despite cold weather related down time and facility constraints in Q4 2003.

The outcome of Flowing's capital and operating cost efficiencies was a 2003 recycle ratio of more than 3.1 times. This is high by any standard, and almost unheard-of for a heavy oil producer.

Financial results

Flowing's 2003 financial results speak to our business plan and the quality of its execution. Strong commodity prices and cost efficiencies combined for an average netback of $18.37 per boe of production. Cash flow for the year was $8.1 million ($0.296 per share) and net earnings were $2.8 million ($0.103 per share).

As a heavy oil producer, Flowing's biggest financial challenge is commodity price risk. Rapid growth has lifted us past the threshold volumes needed to gain cash flow protection and to date we have hedged 1,300 barrels per day to the end of 2004.



Ponoka could be similar to Monitor in scale and impact, but with longer-life reserves.

We are very pleased at Flowing's improved profile in the capital markets. In July 2003 we graduated from the TSX Venture Exchange onto the Toronto Stock Exchange. Brokerage firms have initiated research coverage. Liquidity has improved along with our rising share price. Flowing's market capitalization averaged $125.8 million in February 2004. With four equity issues and the exercise of warrants during 2003, the Corporation received gross proceeds of $33.5 million. Our combined bank lines have been increased to $38 million.

2004 capital program

Flowing's 2004 capital program is budgeted at $40 million, which will fund drilling, facilities, seismic and land acquisitions throughout our core areas. We are targeting average production of more than 4,400 boe per day. We intend to hold average operating costs to $7 per boe and average F&D costs to $7 per boe.

At Wildmere we will develop five further pads to complete 40-acre development of the Lloydminster pool. Wildmere is entering a phase of harvesting net asset value, with very low technical risks. Unit F&D costs should fall due to the reduced capital needs of in-fill wells. Concurrently Flowing will begin developing the Colony and Viking gas potential on our additional 16 sections of undeveloped land at Wildmere, with six wells planned in 2004.

At Monitor, Flowing will develop its three new Dina and Sparky oil discoveries, supported by new 3-D seismic, and drill up to 15 exploration wells targeting Belly River, Viking and Mannville prospects, aimed at maintaining Monitor's natural gas volumes.

The 2004 program will be funded primarily by cash flow and bank lines. Price assumptions are: US$25 per barrel of W.T.I. crude oil, a light-to-heavy differential of US$8.25 per barrel, Cdn$5.61 per thousand cubic feet of natural gas at AECO, and an exchange rate of Cdn$1.32 to US$1.

As in 2003, Flowing will maintain flexibility to respond to changing price conditions or emerging opportunities for accelerated drilling, new plays or strategic acquisitions.

The strategic picture

Entering 2004 Flowing has a large inventory of low-risk, dual-commodity opportunities. However we have always stated our intention, upon reaching certain production and cash flow thresholds, to break out of the W4 region and generate new plays in higher-impact areas that better balance the portfolio between oil and gas. This process is now underway.

Flowing's strategic growth will be supported by the solid base of low-risk production and cash flow at Wildmere and Monitor. Each is capable of delivering further short-term growth, followed by years of steady, profitable production. At Wildmere in particular we foresee significant further additions to net asset value. We believe the 9.3 million barrels of total proved reserves booked to date are only a fraction of the Lloydminster pool's recoverable volume.

Flowing is working on at least three new areas. At Ponoka, Flowing acquired a 2-D seismic program over our 100 percent working-interest undeveloped lands. Locations have been defined over Ellerslie, Glauconite and Colony sand channels, and drilling is to commence in the coming weeks. Offset experience by other area producers indicates these channels can be prolific. Additionally, there

is an emerging coalbed methane (CBM) play in central Alberta that encompasses Ponoka. These gas opportunities in Ponoka could be similar to Monitor in scale and impact, but with longer-life reserves.

The Corporation recently acquired a significant land position (eight sections) on an emerging Milk River natural gas prospect in southwest Saskatchewan. Flowing drilled a well in Q1 2004 designed to evaluate both the Milk River natural gas potential as well as Mannville oil potential on these lands. Additionally, Flowing has entered into a $6 million joint venture with an established area operator to assemble a large land base in this region, which holds extensive potential for shallow, long-life natural gas reserves. Both projects are supported by Flowing's expanded head office team, which now includes an exploration group and an acquisitions specialist, complementing our original core group.

We continue to believe that Flowing has more leverage to create shareholder value through exploration and development of raw land than through acquisitions of producing properties. We are therefore focusing on areas where we could gain a commanding land position to dominate area operations and transform exploration success into a large-scale, repeatable play. However, we are open to acquiring producing properties, particularly oil-focused properties, if the price is advantageous and if the properties offer significant upside potential.

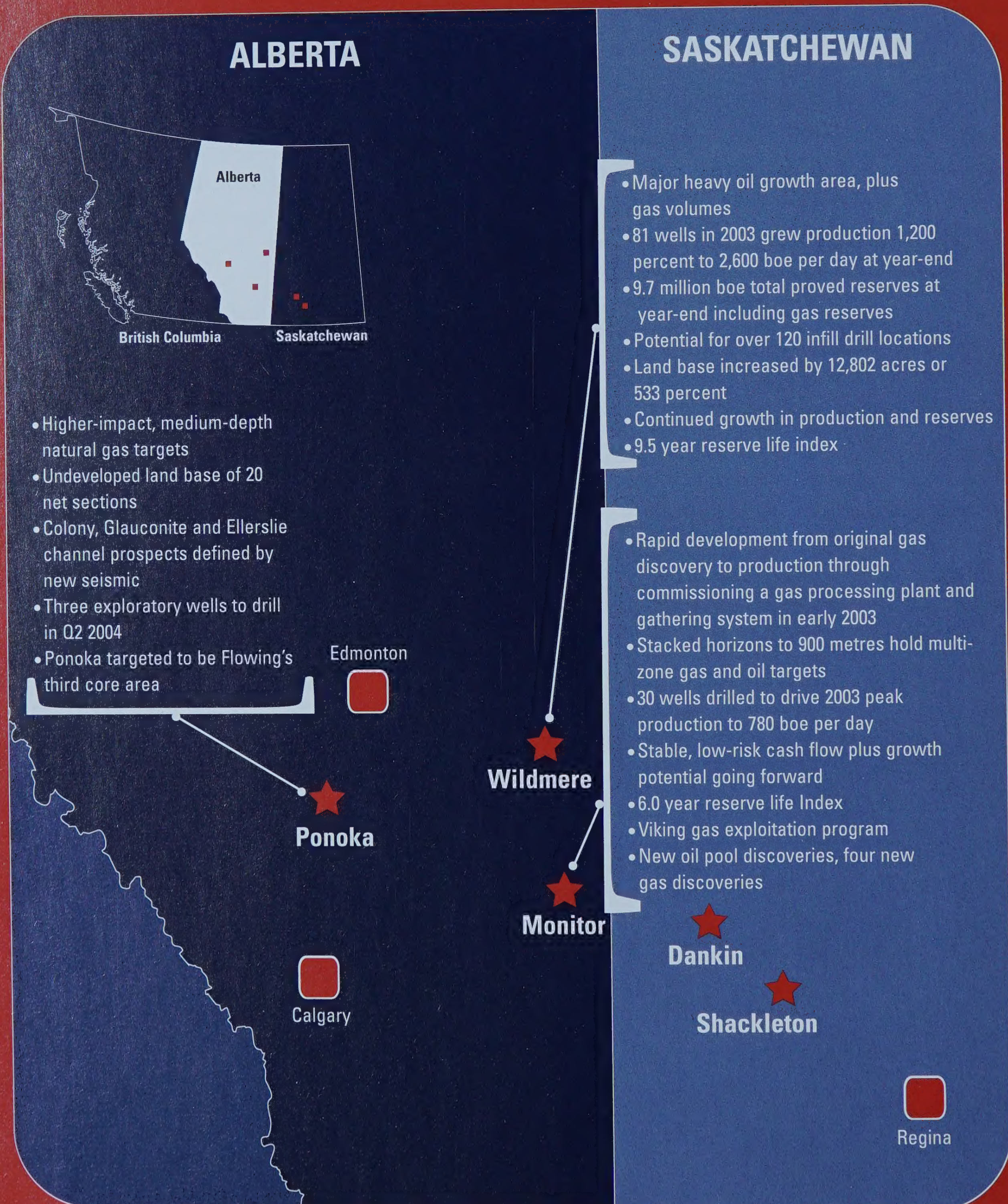
Our milestones to date have depended on the excellence, dedication and commitment of the Flowing people. My deepest thanks go to each of you. Flowing has also benefited from its strong supplier relationships. Such advantages place a small producer on the leading edge of today's energy technologies, improving success rates and cost efficiencies. I would also be remiss if I did not thank our shareholders whose support for Flowing's business plan has been a cornerstone of our success to date.

On behalf of the Board of Directors,

R. Bowman

Robert D. Bowman
President and Chief Executive Officer
March 24, 2004

Review of Exploration and Operations



ALBERTA

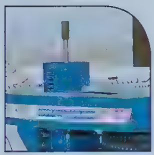
- Higher-impact, medium-depth natural gas targets
- Undeveloped land base of 20 net sections
- Colony, Glauconite and Ellerslie channel prospects defined by new seismic
- Three exploratory wells to drill in Q2 2004
- Ponoka targeted to be Flowing's third core area

SASKATCHEWAN

- Major heavy oil growth area, plus gas volumes
- 81 wells in 2003 grew production 1,200 percent to 2,600 boe per day at year-end
- 9.7 million boe total proved reserves at year-end including gas reserves
- Potential for over 120 infill drill locations
- Land base increased by 12,802 acres or 533 percent
- Continued growth in production and reserves
- 9.5 year reserve life index

- Rapid development from original gas discovery to production through commissioning a gas processing plant and gathering system in early 2003
- Stacked horizons to 900 metres hold multi-zone gas and oil targets
- 30 wells drilled to drive 2003 peak production to 780 boe per day
- Stable, low-risk cash flow plus growth potential going forward
- 6.0 year reserve life Index
- Viking gas exploitation program
- New oil pool discoveries, four new gas discoveries





Overview

Flowing's growth plan is based on the following key principles:

- Low-risk, shallow plays in the W4 corridor of eastern Alberta and western Saskatchewan;
- Multi-horizon natural gas and oil targets;
- Pursue overlooked play concepts to reduce competitive pressures;
- Conduct small acquisitions to gain a strategic foothold;
- Pursue Crown and freehold sales plus farm-ins to expand working interests without large, costly acquisitions;
- Achieve growth in production and reserves through the drill bit;
- Develop and maintain a one- to two-year prospect inventory; and
- Strong focus on cost efficiencies to maximize netbacks and recycle ratios.

Flowing's growth plan met with strong operating and financial success in 2003. Capital expenditures of $55.7 million funded drilling of 111 (108.4 net) wells, increasing production from 284 boe per day entering 2003 to productive capability of 3,200 boe per day in December 2003. Exit volumes consisted of 2,450 barrels per day of heavy- to medium-gravity crude oil and 4.5 million cubic feet per day of natural gas, for a natural gas weighting of 23.4 percent. Flowing made no acquisitions of producing properties in 2003; all growth came through the drill bit on internally-generated prospects.

Operations focused on Flowing's two core areas – Wildmere and Monitor. Flowing formed the nucleus of each core area through small, strategic acquisitions in 2002. In 2003 both areas were expanded significantly. In these core areas the base of undeveloped lands grew to 24,640 net acres at an average working interest of 88 percent at year-end.

Production at Monitor grew from 100 boe per day entering 2003 to a peak of 780 boe per day in April, of which 4.5 million cubic feet per day was natural gas. At Wildmere, production increased to 2,638 boe per day at year-end, of which 91 percent was Lloydminster heavy oil.

Flowing reduced average unit operating costs from $13.32 per boe of production in 2002 to $5.81 per boe in 2003. Combined with strong commodity prices, this generated an average netback of $18.37 per boe. Flowing's finding and development cost averaged $5.90 per boe of new reserves added. This resulted in a recycle ratio of 3.1 times, one of the highest in the Canadian oil and natural gas industry for a company weighted to oil production. These financial results form a strong foundation for Flowing's continued growth.

For 2004 Flowing has budgeted capital expenditures of $40 million. Activity will focus primarily on completing full 40 acre development of the Lloydminster oil pool at Wildmere plus drilling of new natural gas prospects; on a smaller program pursuing a mix of natural gas and oil targets at Monitor; and on Flowing's first round of exploratory drilling at Ponoka and southwest Saskatchewan. Recent land acquisitions and seismic have generated three new natural gas prospects at Ponoka, and Flowing aims to develop Ponoka into its third core area. Flowing is targeting average corporate production of over 4,400 boe per day for 2004.

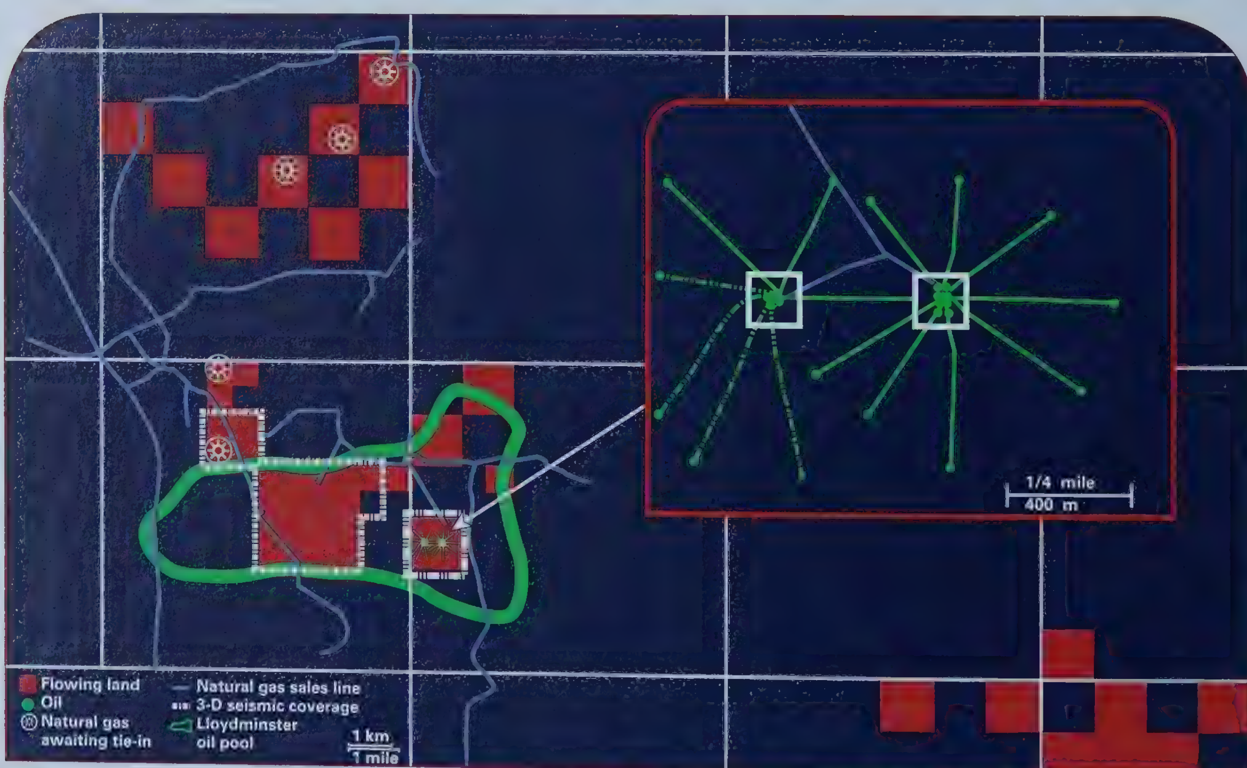
With a view to sustaining longer-term growth, Flowing is prospecting and assembling land to develop our fourth and possibly fifth core areas. Flowing's approach is to generate new gas plays through the drill bit, while seeking acquisitions of suitably-priced producing oil pools with strong upside potential.

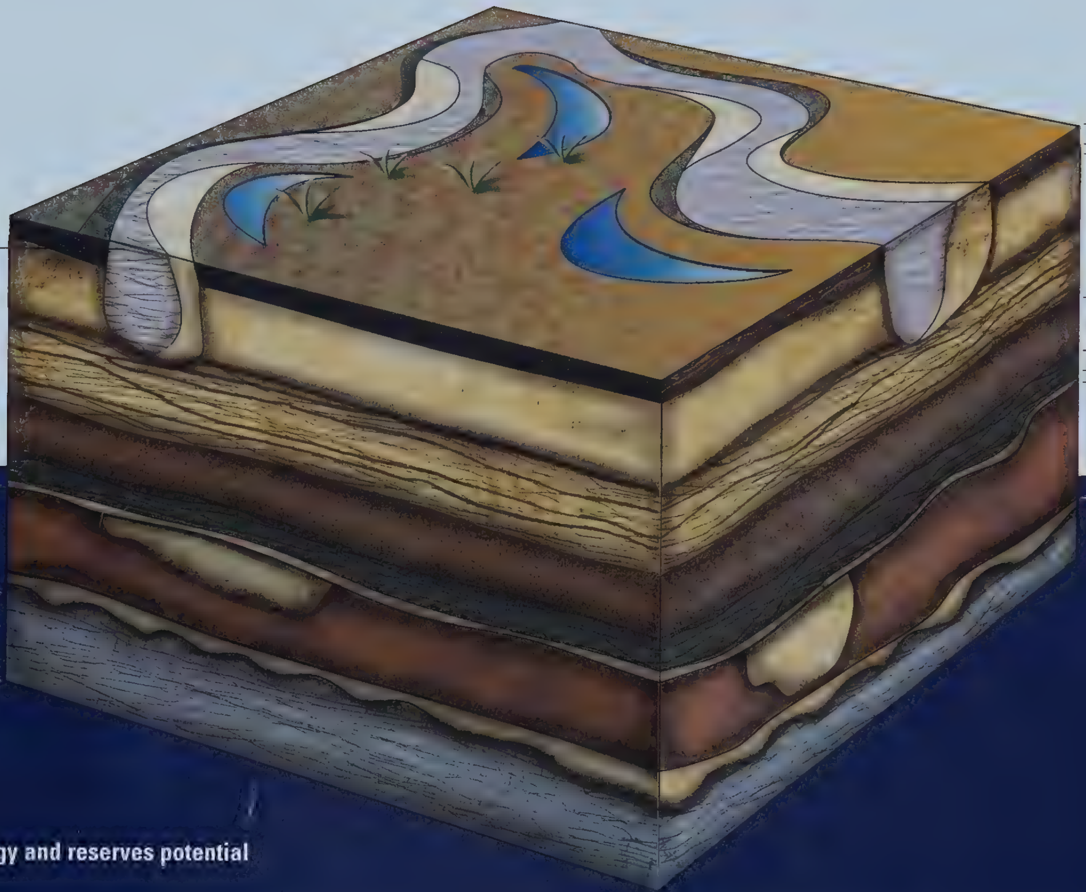
Wildmere

Flowing's Wildmere core area began as a half section that the Corporation had held previously with a farm-in on one-half-section of land in Q1 2002. After drilling one vertical oil well into the Lloydminster heavy oil pool in March 2002, Flowing designed a high-productivity, low-unit-cost, repeatable method to develop this extensive pool (see following sections for detailed discussion).

Recognizing the potential for large-scale volume and reserve additions, Flowing aggressively increased its land position to 2.25 net sections by year-end 2002 and to 17.5 net sections by year-end 2003. Of this total, 6.5 sections overlie the 400 million barrel Lloydminster oil pool. The remainder of the existing Lloydminster pool is held by competitors. Wildmere proved a very low-risk development/exploitation play, yielding highly repeatable opportunities for both Lloydminster oil and shallower Colony gas.

Development under Flowing's multi-well-pad approach began in August 2002. A typical Lloydminster well comes on-stream at 60 barrels per day, a three-fold increase from vertical wells, levelling out at about 40 barrels per day within six months. The typical sand plus water cut is approximately 10 percent in the first year. In 2003, Flowing recognized potential for additional natural gas and oil opportunities in the Wildmere area, and assembled several new exploration blocks outside the Lloydminster pool, bringing the Corporation's land base to 23.75 net sections in March 2004.





Geology and reserves potential

The principal producing horizon at Wildmere is the Lloydminster sand at 650 metres depth, with an average six metres of reservoir thickness. Flowing has mapped this large stratigraphic accumulation covering more than 12 sections of land, of which approximately half underlies Flowing's acreage. As illustrated above, the up-dip trap occurs as a result of shale-filled channels cutting through the marine sand. With regional tilt and up-dip oil migration filling the trap to spill point, more than 250 million barrels of 12 degree API crude oil occurred as original-oil-in-place. Flowing estimates that more than 127 million barrels of original-oil-in-place occurs in Flowing's interest area.

Reservoir performance to date plus simulations by outside consultants suggest that 19.4 percent, or 24.6 million barrels, could be recoverable using Flowing's planned model of horizontal well development on 20-acre spacing. At year-end 2003 Flowing had booked 9.3 million barrels of proved oil reserves in the Lloydminster pool.

Wildmere has also yielded significant Colony gas potential. The Colony sand, at 550 metres depth, is a separate and independent formation partially overlying the Lloydminster pool. The two zones can be encountered in the same wellbore, but there is no geological contact between the Colony and the Lloydminster. Flowing's Colony wells come on-production at up to 500 thousand cubic feet per day. To year-end 2003 Flowing had drilled 10 successful Colony gas wells.

Flowing's undeveloped lands outside the Lloydminster pool are prospective for natural gas from the Colony and Viking formations, and for natural gas or oil from the Sparky and General Petroleums formations at 600 metres average depth.

Wildmere development approach

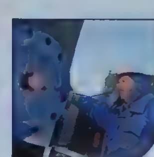
Flowing has designed an innovative method to maximize resource recovery and economic efficiencies at the Lloydminster pool. Each quarter-section (160 acres) receives one vertical plus at least four to eight horizontal wells drilled from a common pad, with a centralized oil battery. Electricity for artificial lift, fluid handling and oil transportation is supplied by on-site generation powered by Flowing-produced natural gas. Some vertical wells are completed up-hole for Colony gas; pads lacking gas production are tied to a gas gathering pipeline carrying 100 percent Flowing gas. Development areas are surveyed by 3-D seismic in advance of drilling.

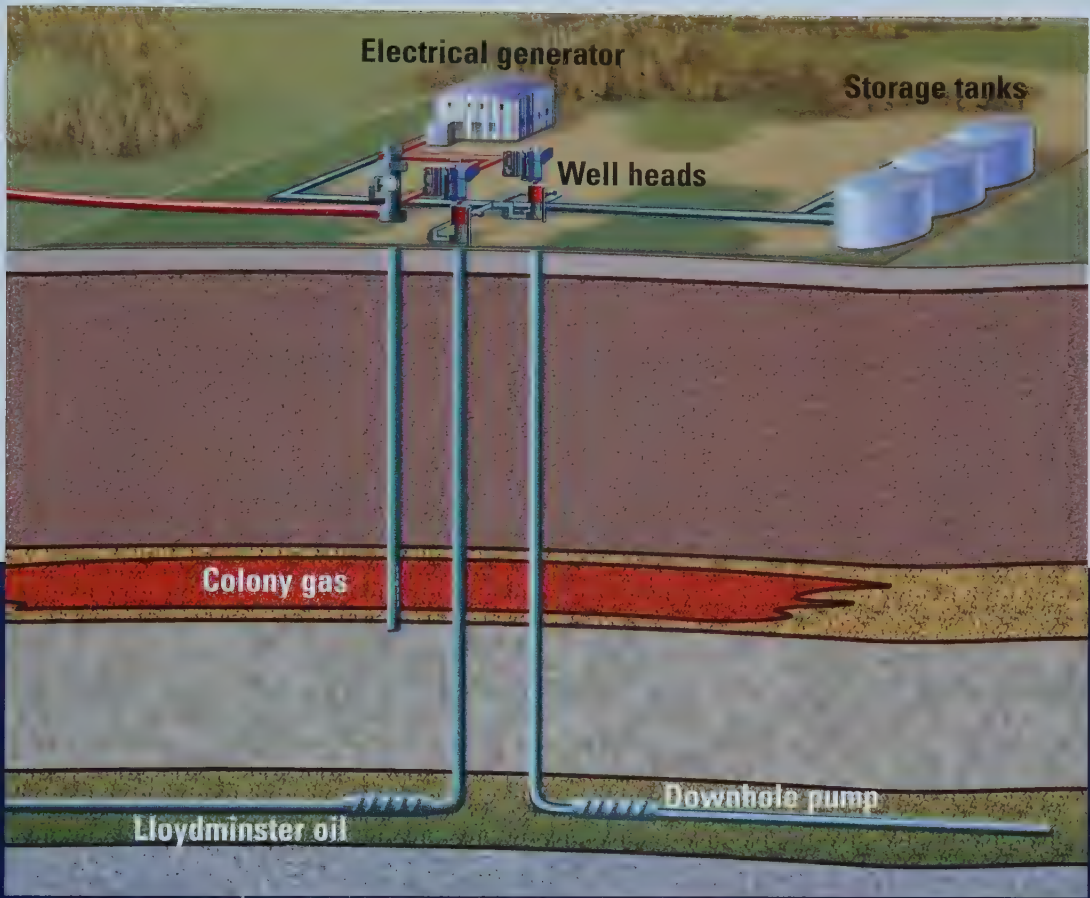
Flowing's 6.5 sections (4,160 acres) overlying the Lloydminster pool should yield a total of 120 oil wells on initial development. After launching the concept in late 2002, Flowing drilled 71 vertical and horizontal oil wells plus ten Colony gas wells in 2003. The facilities for each pad average $490,000 in capital cost. Horizontal wells cost about $330,000 each. Capital expenditures totalled $39.2 million in Wildmere in 2003. Production at year-end was 2,400 barrels per day of heavy oil and 1.5 million cubic feet per day of natural gas.

Unit operating and capital costs are much lower under Flowing's multi-well-pad design than under the traditional approach of drilling separate vertical wells with individual batteries powered by externally-sourced electricity. At mid-year 2003, drilling process improvements reduced completion times for new wells from an average of seven to four-and-a-half days, further reducing capital costs.

A further 50 planned wells should achieve full development on 40-acre spacing by the end of Q2.

As of March 2004 Flowing had a total of 17 net sections of undeveloped land outside the Lloydminster pool. Twenty miles of recently shot 2-D seismic plus acquired trade seismic will be used to generate leads. Flowing will focus on Colony gas potential, aiming to generate the critical mass of production and reserves needed to support construction of company-owned pipelines and compressors. This would enable gas behind pipe to be brought on-production. Currently six gas prospects have been drilled as multi-zone discoveries. These wells will be tested in late Q1 2004 and tied-in after spring break-up. Although natural gas is the primary focus, Flowing's lands also hold oil potential from two zones. Late in 2003 the Corporation drilled a G.P. formation discovery just off the main Lloydminster pool.





Pad development

The illustration depicts Flowing's innovative, cost-reducing, multi-well pad design to develop the Lloydminster pool at Wildmere. Each well-pad develops one-quarter-section (160 acres). An on-site generator produces electricity to lift Lloydminster production and to power fluid separation tanks and sales lines. Each generator consumes approximately 3 percent of the daily production of one Flowing Colony gas well. Pads lacking a Colony well are tied to gas infrastructure. The pad approach significantly reduces capital costs per unit of reserves added. Self-generated power reduces operating costs by \$2-\$3 per boe of production.

Monitor

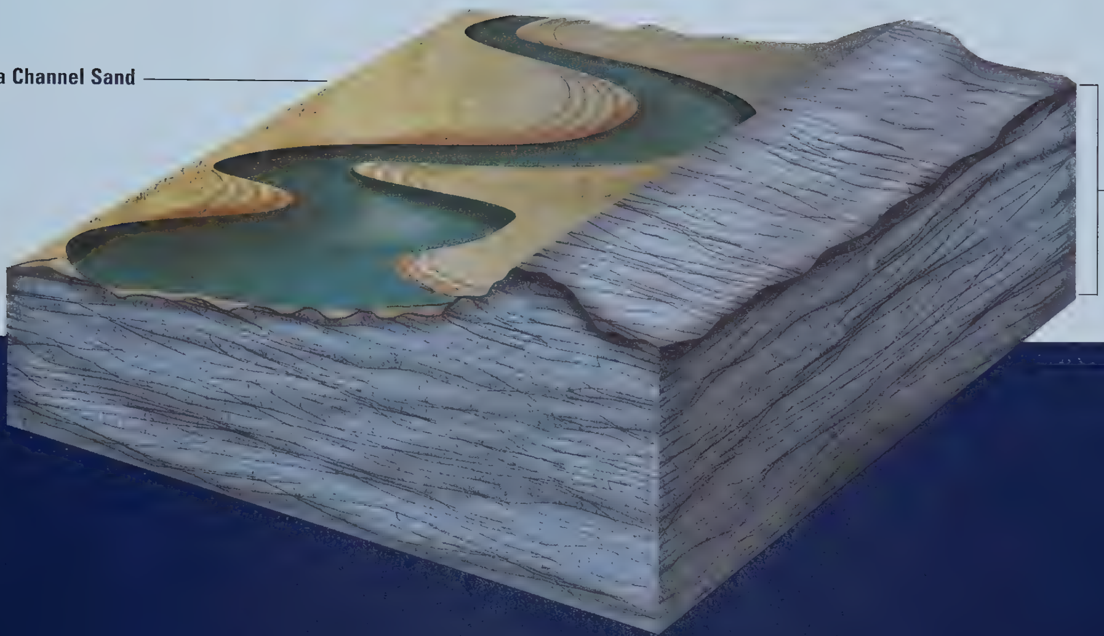
Launched in mid-2002 through a small acquisition and farm-in, Monitor was a growth area for natural gas and oil in 2003. In early 2003 Flowing commissioned a natural gas processing plant and gathering system with 7 million cubic feet daily capacity to handle anticipated growth. Following this, production was ramped up rapidly to a peak of 780 boe per day in early Q2. Natural gas production averaged 2.9 million cubic feet per day through 2003. Capital expenditures in 2003 totalled $15.5 million for new facilities, 30 net wells plus expansion of the land base to 21 net undeveloped sections (13,440 acres) at an average working interest of 82 percent.

In Q1 2003 Flowing made two oil discoveries defined by 2-D seismic in the Sparky and McLaren formations. The wells were brought on-production at a combined 40 barrels per day.

For its gas program Flowing drilled 10 stand-alone Viking wells, all successful, at a density of two wells per section. Eight were tied-in by year-end and the remaining two were tied-in during January 2004. In Q2 Flowing drilled a Belly River natural gas discovery on a seismically-defined prospect. This well is beyond current infrastructure and remains shut-in, but holds potential to become a meaningful play. In October Flowing acquired four sections of undeveloped land and farmed in on two adjoining sections, all lying east of the main Monitor block. These lands contain Mannville, Viking and Belly River gas targets which if successful could be tied into the Monitor plant.

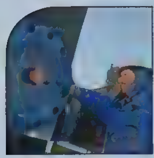
While Monitor will become largely a production-maintenance area, generating reliable cash flow from low-risk natural gas and oil production to fund Flowing's higher-impact growth programs, it offers numerous exploration and development opportunities in half-a-dozen geological zones. Future success will depend on intensively working the Corporation's existing lands and remaining active at Crown sales and farm-in discussions. The Corporation will continue to invest in 3-D seismic to define prospects overlooked by 2-D seismic.This prospecting on existing lands has already generated new leads.

In February 2004, Flowing shot three square miles of new 3-D seismic covering the 2003 discoveries. A planned 15 new wells will target the Dina, McLaren and Sparky for oil and the Belly River, Sparky, McLaren and Viking for natural gas. The first new wells will spud in early Q2. Additional 3-D seismic is also planned. Flowing's primary goal at Monitor is to maintain production at an average 600-700 boe per day through 2004. Positive drilling results in Q2 could generate a stretch target of up to 15 percent production growth.



Geology

Monitor's main exploration targets are Mannville prospects at 800-900 metres in numerous zones including the Dina, Cummings, Lloydminster, Sparky and McLaren. The Dina reservoir, as illustrated above, was deposited by fluvial channels incised into the exposed Paleozoic carbonates. This is a prolific play type for oil exploration in the Monitor area and will be one of the primary targets of the 2004 drilling program. Other prospects feature marine sands and cross-cutting channels in complex relationships that form stratigraphic traps in other Mannville zones. Successful exploitation requires solid technical skills and access to good quality seismic.

Ponoka

Lying along the W4-W5 border, Ponoka's deeper geology offers higher reward potential at somewhat higher technical risk from multi-zone natural gas targets. Flowing exercised passive management over its Ponoka interests in 2002 and early 2003 to concentrate on the lower-risk growth potential at Wildmere and Monitor. Production from three pre-existing Viking oil wells plus one Colony gas well averaged a combined 23 boe per day in 2003.

Flowing's business plan called for initiating exploration at Ponoka once the Corporation had attained certain thresholds for cash flow and production. These conditions were met during 2003, and Flowing's operations are now "graduating" from the shallower, lower-risk but more quickly depleted prospects of the eastern W4 region to the longer-life potential of the W4-W5 border area.

At December 31, 2003, Flowing had 8.7 net sections of undeveloped lands at this highly accessible, year-round area at an average working interest of 99 percent. In Q4 the Corporation shot two lines of 2-D seismic totalling 15 miles across the play, followed by purchases of complementary trade data. This program yielded numerous new leads in Ellerslie, Glauconite and Colony sand channels. Capital spending through year-end was $0.3 million.

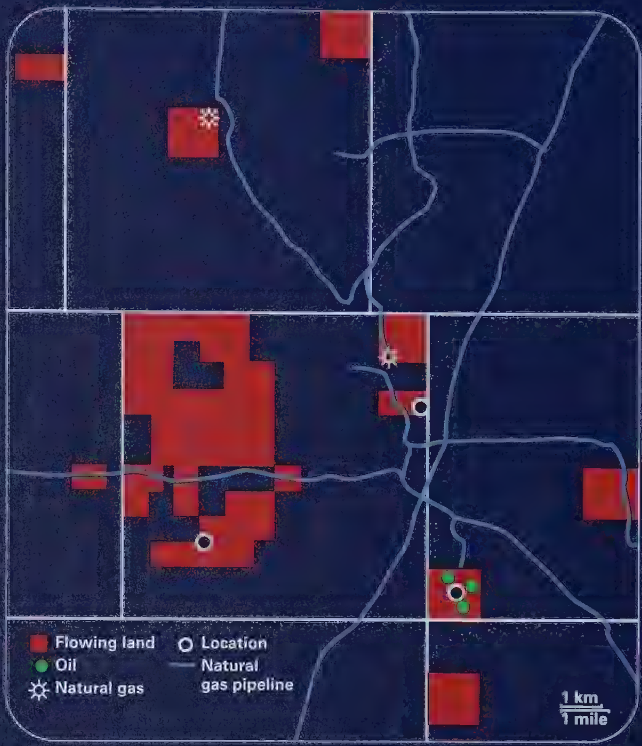
Three high-graded, seismically-defined natural gas prospects have been budgeted for drilling following spring break-up in Q2 2004. These are considered high-impact exploration opportunities that could have significant impact on Flowing's natural gas potential within the short-term. Offset performance by competitors' wells is encouraging, suggesting strong prospects for productive, longer-life natural gas wells. Concurrently Flowing is continuing to expand its land base through acquisitions of freehold rights in this highly competitive area, and is shooting additional 2-D seismic.

Flowing's lands at Ponoka are concentrated across three townships, enabling construction of an efficiently-designed gathering system and facilitating coverage through future 3-D seismic to enable full harvesting of reserves potential. The region has several existing, under-utilized gas plants that could process future production. Flowing is optimistic that Ponoka can be developed into a third core area with production comparable to Monitor at a longer reserve life.

Geology

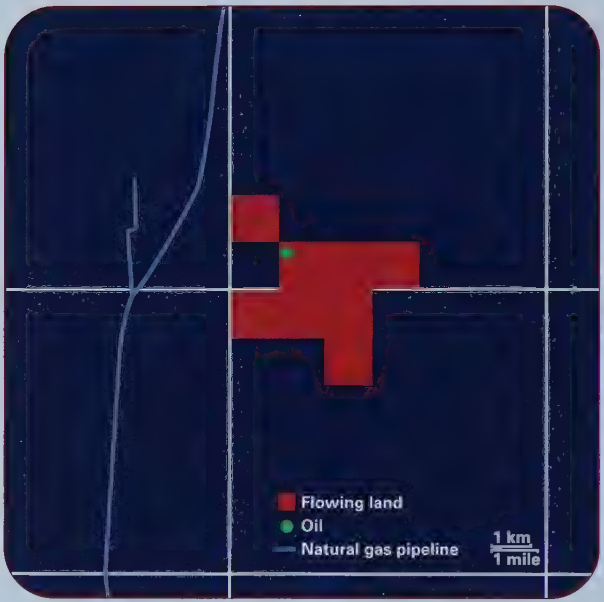
Ponoka's multi-zone prospects are nearly double the depth of pools at Wildmere and Monitor. Flowing is targeting primarily Mannville gas in the Ellerslie, Glauconite and Colony formations at 1,400-1,650 metres depth. The deeper burial of these marine sands and channels results in tighter rock with much higher reservoir pressure and longer-life potential than in Flowing's established areas. In addition Flowing is pursuing an emerging coalbed methane (CBM) play.

Complementing primary targets are Viking prospects at 1,200 metres and shallower Belly River and Edmonton prospects at 500-850 metres, all of which are productive in this region. Ellerslie and Glauconite wells can produce at 2 million cubic feet per day, with typical reserves of 2-3 billion cubic feet and some pools yielding 8 billion cubic feet. Reserve life averages 8-10 years and wells generally perform at a steady exponential decline rate.



Dankin

In late 2003, Flowing moved approximately 65 miles southeast from Monitor and purchased a section of Crown land at Dankin, Saskatchewan. This was followed by a 900 metre exploratory well and the purchase of seven additional sections of Crown land in February 2004. Dankin has Mannville oil potential and a new pool discovery. Flowing plans to develop a new core area at Dankin based on the same guiding principles and play concepts that have proven so successful at Monitor and Wildmere.



Shackleton

In January 2004 Flowing entered into a $6 million joint venture in the Shackleton/Abbey areas of southwest Saskatchewan with an established area operator to assemble a large land base in the region which holds extensive potential for shallow, long-life natural gas reserves.

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) for Flowing Energy Corporation ("Flowing" or the "Corporation") should be read in conjunction with the Annual Information Form, audited financial statements and accompanying notes for the year ended December 31, 2003 and the MD&A, Annual Information Form and audited financial statements for the year ended December 31, 2002.

The information contained herein contains forward looking statements and assumptions, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained herein are as of March 24, 2004 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements.

Revenue, production and prices

Higher production volumes, reflecting a successful drilling program of 111 (108.4 net) wells, compared to 9 (7.6 net) wells in 2002, helped drive record production, cash flow and earnings in 2003.

Flowing had Q4 2003 net revenues of $4.0 million, a 634 percent increase from $0.5 million recorded in Q4 2002, due primarily to growth in production at the Wildmere and Monitor core areas. Cash flow from operations increased to $2.2 million ($0.070 per share) in Q4 2003 from a negative $0.1 million ($0.01 per share) in the same quarter the year before.

Average production in Q4 2003 increased by 833 percent year-over-year, to 2,193 boe per day from 235 boe per day in Q4 2002. Natural gas accounted for 31 percent of Q4 corporate production compared to 29 percent in Q4 2002. Flowing received an average of $19.20 (2002 – $27.47) per barrel of oil and $5.24 (2002 – $5.05) per million cubic feet of natural gas during the quarter, resulting in a combined corporate price of $23.04 (2002 – $28.19) per boe.

For the year ended December 31, 2003 Flowing recorded revenue of $12.2 million, cash flow of $8.1 million ($0.296 per share) and net earnings of $2.8 million ($0.103 per share) compared to revenue of $1.1 million, negative cash flow of $0.2 million ($0.012 per share) and a net loss of $0.5 million ($0.031 per share) in 2002. These major increases were due primarily to higher average production volumes.

Average production for the year ended December 31, 2003 increased by 1,035 percent to 1,384 boe per day from 122 boe per day in 2002, reflecting the impact of successful drilling at Monitor and Wildmere during the year. Productive capability in December 2003 was 3,200 boe per day compared to 284 boe per day in 2002, an increase of 1,027 percent. For the year ended December 31, 2003 Flowing received $22.00 (2002 – $30.36) per barrel of oil and $6.37 (2002 – $4.08) per million cubic feet of natural gas, resulting in a combined corporate price of $29.62 (2002 – $27.82) per boe.

Operating and net earnings

Operating income for the fourth quarter and year ended December 31, 2003 was $2.8 million and $9.3 million respectively, compared to $0.3 million and $0.5 million for the same periods in the prior year, reflecting significant increases in production.

Flowing had net earnings of $0.6 million ($0.020 per share) in Q4 2003 compared to a loss of $0.2 million ($0.014 per share) in the same period in 2002. Net earnings for the year ended December 31, 2003 were $2.8 million ($0.103 per share) compared to a loss of $0.5 million ($0.031 per share) for 2002.

Major expenses

Fourth-quarter 2003 operating expenses were $1.3 million ($6.38 per boe) compared to $0.3 million ($13.39 per boe) in Q4 2002. Operating expenses for the year ended December 31, 2003 were $2.9 million ($5.81 per boe) versus $0.6 million ($13.32 per boe) in 2002. During the year, the Corporation implemented a number of operational efficiencies, including installation of natural gas-fired heat and power generators at Wildmere that take advantage of the Corporation's natural gas production to help produce crude oil. This initiative was reflected in lower corporate operating expense on a per unit basis and a 35 percent per barrel reduction in heavy oil operating expenses since the beginning of the year. Operating expenses are expected to increase as the Corporation expands into new operating areas; however, the Corporation will aim to hold operating expenses at $7 per boe in the coming year.

General and administrative (G&A) costs were $0.5 million ($2.49 per boe) in Q4 2003 and $0.9 million ($1.83 per boe) for the full year, and are net of $0.5 million and $1.3 million, respectively, of capitalized recoveries. Due to the Corporation's significantly higher production base, Flowing's 2003 G&A costs compare very favourably to G&A costs of $0.3 million ($16.39 per boe) for Q4 2002 and $0.6 million ($13.81 per boe) for the year ended 2002 (no capitalized recoveries were made in 2002). While G&A costs will increase in absolute terms with future growth, Flowing expects such costs, after capitalized recoveries, will remain low per unit-of-production as the Corporation continues to grow production volumes.

Interest expense on the capital lease, since inception on March 31, 2003 was $0.16 million of which $0.05 million was incurred in Q4. Interest expense associated with utilizing the line of credit was $0.07 million in Q4 (Q4 2002 – $0.031 million) and $0.14 million (2002 – $0.066 million) for 2003. The Corporation anticipates that interest expense will increase as it utilizes its increased line of credit in the coming months to finance capital expenditures. Interest on the capital lease will decrease over time as the principal amount is paid out.

Depletion expense for Q4 2003 and the year ended December 31, 2003 was $1.4 million ($6.81 per boe) and $3.6 million ($7.15 per boe), respectively. This compares to depletion expense for Q4 2002 and the year ended December 31, 2002 of $0.2 million ($10.44 per boe) and $0.5 million ($11.05 per boe), respectively. The decreased rates per boe were a result of increased reserves in Flowing's core areas in 2003.

Future income taxes were $0.3 million for Q4 2003 (Q4 2002 – recovery of $0.1 million) and $1.6 million for the year ended December 31, 2003 (2002 – recovery of $0.2 million).

Royalties

Flowing incurred net royalties in Q4 2003 of $0.6 million (Q4 2002 – $0.06 million) resulting in a royalty rate of $3.21 per boe or 13.6 percent of gross revenue (Q4 2002 – $2.68 or 9.5 percent, respectively). Net royalties for the year ended 2003 were $3.0 million (2002 – $0.14 million) for a royalty rate of $5.87 (2002 – $3.06) per boe or 19.8 percent (2002 – 11.0 percent) of gross revenue.

Flowing expects royalties to average approximately 20-25 percent of gross revenues in 2004. The increase is related to expected increases in natural gas production.

Drilling and capital expenditures

In Q4 2003 Flowing continued to execute its capital expenditure program which amounted to $23.6 million compared to $2.5 million in the same period the year before. For the year ended December 31, 2003, Flowing's capital expenditures were $55.7 million compared to $4.9 million for 2002. During Q4, Flowing drilled 43 (42.75 net) wells, including two natural gas wells and one salt water disposal well at Monitor and 36 (35.75 net) oil wells and four natural gas wells at Wildmere. Most of these wells were tied in by year-end. For all of 2003 Flowing drilled 111 (108.4 net) wells of which 77 (76.4 net) were oil, 31 (29 net) were gas, two were dry holes and one was a salt water disposal well. Early in 2003 Flowing commissioned its Monitor gas processing plant and gathering system. These assets were refinanced effective March 31, 2003 through a $3.5 million sale-leaseback arrangement with the Corporation's banker.

The following table summarizes capital expenditures for Q4 2003 and the year ended December 31, 2003:

	[redacted]	[redacted]	3 months ended December 31, 2002	12 months ended December 31, 2002
Land	[redacted]	[redacted]	$ 380,552	$ 1,268,948
Seismic	[redacted]	[redacted]	190,963	376,919
Drilling and intangibles	[redacted]	[redacted]	1,416,762	2,635,265
Facilities and equipment	[redacted]	[redacted]	506,288	571,126
Total	[redacted]	[redacted]	$ 2,494,565	$ 4,852,258

Flowing has budgeted capital expenditures of $40 million in 2004 for facilities, seismic, land and drilling. These planned expenditures will be financed through a combination of cash flow and bank facilities.

Reserves

Flowing's reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. (GLJ), independent reservoir engineers, effective January 1, 2004, using the new standards required under the Canadian Securities Administrators' National Instrument 51-101.

The key results of the most recent evaluation are provided in the table below, accompanied by results of the previous GLJ evaluation, effective December 31, 2002, using the previous reporting standards under National Policy 2B:

(mmboe)	December 31, 2002 (NP 2B basis)	January 1, 2004 (NI 51-101 basis)	% increase
Total proved	1.049	10.648	915
Total proved plus probable	1.463	12.589	760

Flowing's new reserves were added at an average finding and development (F&D) cost of $5.90 per boe on a proved plus probable reserves versus a F&D cost of $4.62 per boe in 2002. Virtually 100 percent of the increase was achieved through successful oil and natural gas drilling on internally-generated Flowing prospects, which the Corporation considers a significant accomplishment.

GLJ's report indicates that as at January 1, 2004 Flowing's total proved plus probable oil and natural gas assets had a net present value, based on forecast prices and costs, of $154.9 million undiscounted and $88.4 million discounted at 10 percent.

Details concerning Flowing's reserves volume and value at January 1, 2004, including the effects of ARTC and AGCA, are provided below, using the new NI 51-101 standards:

January 1, 2004 (mmboe)	Discount rate	Proved producing	Total proved	Total probable	Total proved plus probable
Corporation interest		7.474	10.648	1.941	12.589
Net after royalty		6.841	9.453	1.732	11.185
Before tax present value ($ millions)					
	0%	104.4	127.1	27.8	154.9
	8%	70.3	85.0	11.5	96.5
	10%	65.3	78.6	9.8	88.4
	15%	56.0	66.5	6.9	73.4
	20%	49.5	57.8	5.3	63.1

Liquidity and capital resources

During 2003, with the completion of four equity issuances and exercise of the Series A, B, and C warrants, Flowing received gross proceeds of $33.5 million to fund capital expenditures. In addition, the Corporation increased its credit facilities, including the capital lease, with its banker to $20.2 million by December 31, 2003. As at December 31, 2003 the Corporation had a working capital deficiency of $14.5 million.

In late March 2004, the credit facilities with the Corporation's banker were increased to $38 million. Currently, Flowing has $13.8 million of unutilized credit facilities.

Common share trading

The following table summarizes the Corporation's common share trading activity for the years ended December 31, 2003 and December 31, 2002.

Year ended December 31	2003	2002
Trading volume (thousands)	13,256.1	4,409.2
Daily average	36,318	12,080
Share price		
High	$ 3.10	$ 1.00
Low	$ 0.94	$ 0.16
Market capitalization		
Shares outstanding	38,970,186	20,430,344
Year-end share price	$ 2.61	$ 0.92
Total ($000)	$ 101,712.2	$ 18,795.9

Business risks

The oil and natural gas exploration and development industry is inherently risky. Operational risks include finding economic oil and natural gas reserves, production once the reserves are discovered, costs of materials and services, access to producing facilities and transportation, and the ability to attract and retain, at a reasonable cost, the best human resources available.

Financial risks that are not within Flowing's control include the fluctuation in commodity prices and foreign exchange, provincial and federal regulations, royalties and taxes and interest rates. The Corporation has entered into certain crude oil swap contracts to hedge against a downturn in commodity prices.

Flowing endeavours to manage certain costs by focusing on controlling finding and development costs, operating costs and general and administrative expenses. Flowing's strategy of focusing on core geographical areas and geological targets result in controlling capital risk.

The Corporation also faces environmental risks associated with the pollution of ground, air and water. The Corporation adheres to and promotes the highest standards of safety and environmental protection in all its operations. A comprehensive insurance program is maintained to mitigate risks and to protect against significant losses. This program protects against losses from pollution, well blowouts and other forms of asset damage.

Selected quarterly information

The following table sets forth selected financial information of the Corporation for each financial quarter of the Corporation for the years ended December 31, 2003 and December 31, 2002.

	2003				2002			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Oil and NGLs (bbls per day)	1,504.3	781.5	422.4	211.0	166.7	52.0	39.0	17.4
Natural gas (mcf per day)	4,131.7	4,702.7	4,209.6	2,546.0	409.9	237.6	310.0	268.0
Barrels of oil equivalent (boe per day @ 6:1)	2,192.9	[illegible]	1,124.0	635.6	235.1	91.6	90.7	62.1
Financial ($, except as noted)								
Revenue, net royalties	$ 4,047,152	$ 3,271,985	$ 2,755,388	$ 2,139,411	$ 551,664	$ 217,096	$ 177,160	$ 138,771
Cash flow	$ 2,214,659	$ 2,327,542	$ 1,926,651	$ 1,667,936	$ (105,642)	$ (32,082)	$ (42,321)	$ 416
Per share basic	0.070	0.089	$ 0.077	$ 0.071	$ (0.012)	$ –	$ –	$ –
Per share diluted	0.065	0.060	$ 0.057	$ 0.053	$ (0.012)	$ –	$ –	$ –
Net earnings (loss)	641,316	$ 712,438	$ 799,196	$ 671,772	$ (224,333)	$ (122,448)	$ (81,970)	$ (42,901)
Per share basic	0.020	0.027	$ 0.032	$ 0.028	$ (0.014)	$ (0.009)	$ (0.006)	$ (0.003)
Per share diluted	0.019	$ 0.019	$ 0.024	$ 0.021	$ (0.014)	$ (0.009)	$ (0.006)	$ (0.003)
Capital expenditures	$ 23,640,443	$ 13,770,787	$ 10,348,874	$ 7,983,721	$ 2,494,565	$ 1,373,964	$ 629,784	$ 353,945
Working capital (deficiency)	$ (14,457,461)	$ (10,476,862)	$ (7,776,196)	$ 249,391	$ (281,543)	$ (762,308)	$ (469,781)	$ 202,474
Basic shares outstanding	38,970,186	30,933,468	26,990,952	25,924,306	20,430,344	16,584,186	13,584,186	13,584,186
Per unit information								
Natural gas ($ per mcf)	[illegible]	[illegible]	6.95	$ 8.83	$ 5.05	$ 2.55	$ 4.19	$ 3.42
Oil and natural gas liquids ($ per bbl)	[illegible]	[illegible]	27.04	$ 34.56	$ 27.47	$ 39.75	$ 26.38	$ 35.91
Oil equivalent ($ per boe)	[illegible]	[illegible]	35.12	$ 46.67	$ 28.19	$ 29.17	$ 25.65	$ 24.82
Operating netback ($ per boe)	[illegible]	[illegible]	21.26	$ 31.12	$ 12.12	$ 13.03	$ 6.76	$ 11.44
Net wells drilled								
Natural gas	[illegible]	[illegible]	[illegible]	7.5	1.0	–	–	1.0
Oil	[illegible]	[illegible]	[illegible]	[illegible]	2.8	1.8	–	1.0
Dry		[illegible]	[illegible]		–	–	–	–
Other	[illegible]		[illegible]	–	–	–	–	–
Total	[illegible]	[illegible]	[illegible]	12.5	3.8	1.8	–	2.0
Success rate	[illegible]	[illegible]	[illegible]	100%	100%	100%	–	100%

New accounting standards

In the coming year, Flowing intends to adopt recommendations of the following CICA Handbook sections:

Accounting Guideline ACG-13 – Hedge Accounting

Accounting Guideline ACG-16 – Full Cost Accounting – Oil and Gas

CICA HB 3110 – Asset Retirement Obligations

CICA HB 3063 – Impairment of Long-Lived Assets

CICA HB 3475 – Disposal of Long-Lived Assets

The adoption of the above accounting recommendations is not expected to have a material impact on the Corporation.

The adoption of the following accounting recommendation is expected to reduce annual net income for 2004 by approximately $500,000 based on current estimates.

CICA HB 3870 – Stock-Based Compensation and other Stock-Based Payments.

Management's Report

These financial statements are the responsibility of the Management of Flowing Energy Corporation ("Flowing"). They have been prepared in accordance with Canadian generally accepted accounting principles using Management's best estimates and judgements, where appropriate.

Management is responsible for the reliability and integrity of the financial statements, notes to the financial statements and other financial information contained in this report. Estimates are sometimes necessary in the preparation of these statements because a precise determination of some assets and liabilities depends on future events. Management has based these estimates on careful judgements and believes they are properly reflected in the accompanying financial statements. Management is also responsible for maintaining a system of internal controls designed to provide reasonable assurance that assets are safeguarded and that accounting systems provide timely, accurate and reliable financial information.

The Board of Directors of Flowing is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal controls through its Audit Committee which is comprised of independent Directors and meets at least every quarter. The Board also meets with Management to ensure that Management's responsibilities are fulfilled, to review financial statements and to recommend approval of the financial statements. The Board of Directors has approved the information contained in the financial statements. An independent auditor, Kenway Mack Slusarchuk Stewart LLP, has audited the financial statements of Flowing in accordance with Canadian generally accepted auditing standards and has provided an independent opinion.

Robert D. Bowman
President and Chief Executive Officer
Calgary Alberta
March 4, 2004

David G. Mallory
Chief Financial Officer and Corporate Secretary

Auditors' Report

To: The Shareholders of Flowing Energy Corporation

We have audited the balance sheets of Flowing Energy Corporation as at December 31, 2003 and 2002 and the statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Kenway Mack Slusarchuk Stewart LLP

Chartered Accountants
Calgary, Alberta
March 4, 2004

Balance Sheets

As at December 31,	2003	2002
Assets		
Current assets		
Cash and cash equivalents	$ 725,559	$ –
Accounts receivable	4,480,352	399,556
Share subscriptions receivable		633,360
Future income taxes (Note 9)	482,900	422,600
Promissory note receivable	10,000	15,000
	5,698,811	1,470,516
Petroleum and natural gas properties and equipment (Note 3)	58,396,780	6,125,199
	$ 64,095,591	$ 7,595,715
Liabilities and Shareholders' Equity		
Current liabilities		
Bank indebtedness (Note 4)	$	$ 610,807
Accounts payable and accrued liabilities	19,641,464	1,141,252
Current portion of obligation under capital lease (Note 7)	514,808	–
	20,156,272	1,752,059
Convertible promissory note due to shareholder (Note 5)		500,000
Obligation under capital lease (Note 7)	2,562,038	–
Future income taxes (Note 9)	2,979,800	637,200
Provision for future site restoration and abandonment	111,990	52,278
	25,810,100	2,941,537
Shareholders' Equity		
Share capital (Note 8)	34,384,448	5,726,728
Warrants (Note 8)	2,066,006	–
Contributed surplus	82,865	–
Retained earnings (deficit)	1,752,172	(1,072,550)
	38,285,491	4,654,178
	$ 64,095,591	$ 7,595,715

Commitments (Note 12)

Subsequent event (Note 13)

See accompanying notes.

Approved on behalf of the Board:

Director

Director

Statements of Earnings and Retained Earnings

Years ended December 31,	[illegible]	2002
Revenue		
Petroleum and natural gas, net of royalties	$ 12,213,936	$ 1,084,691
Expenses		
Depletion, depreciation and amortization	3,609,801	491,626
Operating	2,935,069	593,044
General and administrative	924,515	614,993
Interest on capital lease	157,984	–
Interest	112,445	66,280
	7,769,814	1,765,943
Earnings (loss) before income taxes	4,444,122	(681,252)
Future income taxes (recovery) (Note 9)	1,619,400	(209,600)
Net earnings (loss)	2,824,722	(471,652)
Deficit, beginning of year	(1,072,550)	(600,898)
Retained earnings (deficit), end of year	$ 1,752,172	$ (1,072,550)
Net earnings (loss) per share (Note 8)		
Basic	$ [illegible]	$ (0.031)
Diluted	$ [illegible]	$ (0.031)

See accompanying notes.

Statements of Cash Flows

Years ended December 31,	2003	2002
Operating activities		
Net earnings (loss)	2,824,722	$ (471,652)
Items not affecting cash:		
Depletion, depreciation and amortization	3,609,801	491,626
Future income taxes (recovery)	1,619,400	(209,600)
Write-down of investment in Sarnia Minerals Limited		9,999
Compensation expense on stock options	82,865	–
Cash flow from operations	8,136,788	(179,627)
Net change in non-cash operating working capital (Note 14)	(913,982)	(158,451)
	7,222,806	(338,078)
Financing activities		
Issuance of common shares and warrants, net of costs	30,886,626	3,709,736
Receipt of share subscriptions receivable	633,360	–
Receipt of promissory note receivable	5,000	–
Proceeds on obligation under capital lease	3,500,000	–
Repayment of obligation under capital lease	(423,155)	–
Retirement of promissory note receivable		25,000
Issue of promissory note receivable		(15,000)
	34,601,831	3,719,736
Investing		
Expenditures on petroleum and natural gas properties and equipment	(55,743,824)	(4,852,258)
Expenditures on site restoration and abandonment	(77,845)	–
Net change in non-cash investing working capital (Note 14)	15,333,398	473,103
	(40,488,271)	
Increase (decrease) in cash and cash equivalents	1,336,366	(997,497)
Cash and cash equivalents (bank indebtedness), beginning of year	(610,807)	386,690
Cash and cash equivalents (bank indebtedness), end of year	725,559	$ (610,807)

Supplemental cash flow information (Note 14)

See accompanying notes.

Notes to the Financial Statements

(December 31, 2003 and 2002)

1. Description of business

Flowing Energy Corporation ("the Corporation") was incorporated under the Business Corporations Act (Alberta) on June 3, 1996. The Corporation's principal business activity is the exploration, exploitation, development and production of petroleum and natural gas reserves in the Provinces of Alberta and Saskatchewan.

Effective September 30, 2002 Flowing Energy Inc., a wholly-owned and the only subsidiary of the Corporation was dissolved and all of its assets and liabilities were transferred to the Corporation.

2. Significant accounting policies

(a) Basis of presentation

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles which require management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In the opinion of management, these financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

(b) Measurement uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment, the provision for future site restoration and abandonment costs and the ceiling test calculation are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(c) Revenue recognition

Petroleum and natural gas revenues are recognized when title passes from the Corporation to its customers.

(d) Cash and cash equivalents

Cash and cash equivalents include bank overdrafts, revolving credit facilities and those short-term money market instruments which, on acquisition, have an original term to maturity of three months or less.

(e) Financial instruments

The Corporation enters into crude oil swap contracts, when it is deemed appropriate, to reduce the exposure to adverse fluctuations in commodity prices to protect cash flow. The Corporation does not enter into derivative financial instruments for trading or speculative purposes.

These crude oil swap contracts are not recognized on the balance sheet.

Realized gains and losses relating to the crude oil swap contracts are recognized as part of net petroleum and natural gas revenue and cash flows concurrently with the settlement of the commodity swap transaction.

2. Significant accounting policies (continued)

(f) Petroleum and natural gas properties and equipment

The Corporation follows the full-cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas equipment and overhead charges directly related to exploration and development activities.

Undeveloped and unproved properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the full-cost pool subject to depletion.

The Corporation conducts a cost recovery ceiling test to ensure capitalized costs, less accumulated depletion and depreciation, future income taxes and the accumulated provision for future site restoration and abandonment costs do not exceed the estimated future net revenues plus the cost of unproved properties, net of impairments. The future net revenues are calculated based on proved reserves, using year-end prices and costs. Estimated future capital costs, recurring general and administrative expenses, future financing costs, future site restoration and abandonment costs, and income taxes are deducted in determining future net revenues. Any amount carried on the balance sheet in excess of the ceiling test limit is charged to current operations as additional depletion.

Proceeds from the disposition of petroleum and natural gas properties and equipment are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

(g) Depletion, depreciation and amortization

Capitalized costs including assets under capital lease, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves of petroleum and natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of natural gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are initially excluded from the depletion calculation.

Other assets are carried at cost less accumulated amortization. Amortization is provided based on the estimated useful lives of the assets on a straight-line basis as follows:

Motor vehicles	2 years
Furniture and fixtures	5 years
Computer equipment	3 years
Leasehold improvements	term of the lease

2. Significant accounting policies (continued)

(h) Joint ventures

A small portion of the Corporation's exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Corporation's proportionate interest in such joint activities.

(i) Leases

Leases entered into by the Corporation as lessee that transfer substantially all the benefits and risks of ownership to the lessee are recorded as capital leases and included in petroleum and natural gas properties and equipment and long-term debt. All other leases are classified as operating leases under which leasing costs are recorded as expenses in the period in which they are incurred.

(j) Provision for future site restoration and abandonment

Estimated future site restoration and abandonment costs are provided for over the life of the proved reserves on a unit-of-production basis. Costs, net of salvage values, are estimated each period by management based on current regulations, costs, technology and industry standards. The annual charge is recorded as additional depletion, depreciation and amortization. Actual site restoration and abandonment costs are charged against the accumulated provision as incurred.

(k) Flow-through shares

Resource expenditure deductions funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Corporation, the future income tax liability and the carrying value of the shares issued are adjusted by the effect of the tax benefits renounced to subscribers when the corresponding exploration and development expenditures are incurred.

(l) Stock-based compensation

The Corporation has a stock-based compensation plan, which is described in Note 8. For stock options granted to employees and directors, the Corporation accounts for its stock-based compensation plan using the intrinsic-value method. Under this method, no costs are recognized in the financial statements for share options granted to employees or directors when the options are issued at market value. Consideration paid by directors, officers and employees on the exercise of stock options under the stock option plan is recorded as share capital.

Stock options granted to non-employees are accounted for in accordance with the fair value method of accounting for stock-based compensation. The fair value of stock options is determined using the Black-Scholes option pricing model. For stock options issued to non-employees, the fair value is recorded as compensation expense and contributed surplus in the financial statements.

(m) Future income taxes

The Corporation follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are calculated based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the financial statements and their respective tax bases. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in income in the period in which the change occurs.

2. Significant accounting policies (continued)

(n) Per share information

Per share information is calculated on the basis of the weighted average number of common shares outstanding during the fiscal year. Diluted per share information reflects the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Corporation upon the exercise of in-the-money stock options would be used to buy back common shares at the average market price for the period.

3. Petroleum and natural gas properties and equipment

	2003		
	[illegible]	[illegible]	[illegible]
Petroleum and natural gas properties and equipment	[illegible]	[illegible]	[illegible]
Assets under capital lease	[illegible]	[illegible]	[illegible]
Other assets	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	$ 58,396,780

	2002		
	Cost	Accumulated depletion, depreciation and amortization	Net book value
Petroleum and natural gas properties and equipment	$ 7,185,969	$ 1,091,539	$ 6,094,430
Other assets	35,089	4,320	30,769
	$ 7,221,058	$ 1,095,859	$ 6,125,199

During the year ended December 31, 2003, the Corporation capitalized $1,339,860 (2002 – $nil) of general and administrative expenses directly related to petroleum and natural gas properties and equipment.

The cost of unproved properties excluded from the depletion base as at December 31, 2003 was $2,961,143 (2002 – $664,664).

As at December 31, 2003 the estimated future site restoration and abandonment costs to be amortized over the remaining proved reserves are $2,987,105 (2002 – $516,000) of which $137,557 (2002 – $31,229) has been included in depletion, depreciation and amortization.

Future development costs on proven undeveloped reserves of $15,593,000 are included in the depletion and depreciation calculation.

4. Bank indebtedness

	2003	2002
Bank overdraft	[illegible]	$ (100,807)
Demand bank loan	[illegible]	(510,000)
	[illegible]	$ (610,807)

The Corporation has a revolving credit facility with a major Canadian financial institution. On October 23, 2003, this credit facility was increased from $6.0 million to $17.0 million. Borrowings under this facility are limited to 67 percent of the net present value of the revenue from petroleum and natural gas properties after deducting the Corporation's other financial obligations. Borrowings under this facility are also limited to a borrowing base as determined from time to time by the bank. The facility bears interest at the bank's prime rate and is repayable on demand. The assets of the Corporation are pledged as security for amounts drawn on the credit facility under a general security agreement.

5. Convertible promissory note due to shareholder

In 2000 the Corporation issued a $500,000, 8 percent Subordinated Convertible Promissory Note to a shareholder for cash. The shareholder has directors that are also directors of the Corporation. The note is due September 30, 2005 but may be repaid at any time, bears interest at 8 percent per annum and is fully subordinated to all senior debt. During the year ended December 31, 2003, $30,000 (2002 – $40,000) of interest was paid on the note. The holder of the note may convert the principal of the note into common equity of the Corporation at $0.75 per share in year one and two, at $0.85 per share in year three, at $0.95 per share in year four, and at $1.05 per share in year five. During the year, the holder of the note converted the principal into 588,235 common shares. Additionally, the shareholder or its nominee held a two-year option from August 23, 2000 to participate, prior to spud date, for a maximum of $1.67 million, in the farm-in of petroleum and natural gas plays of the Corporation in the Province of Alberta on a 100 for 50 basis using standard CAPL terms. This option expired on August 23, 2002.

6. Convertible debentures

In 2000 the Corporation issued $300,000 convertible debentures bearing 5 percent interest payable annually and due on February 1, 2003. The convertible debentures were convertible into 1,200,000 common shares at $0.25 per share on or before January 31, 2002 or 1,000,000 common shares at $0.30 per share between February 1, 2002 and February 1, 2003. Of these convertible debentures, $280,000 was issued to directors, officers or consultants of the Corporation. On January 31, 2002, the $300,000 convertible debentures were converted into 1,200,000 common shares at $0.25 per share. During the year ended December 31, 2003 $nil (2002 – $1,250) of interest was paid on the convertible debentures.

7. Obligation under capital lease

Effective March 31, 2003, the Corporation refinanced a gas processing plant and gathering system for $3.5 million through a sale-leaseback transaction. Lease payments of $58,114 (principal and interest) are payable monthly, commencing March 31, 2003 for a five-year term at an interest rate of 6.42 percent. The Corporation has an option to acquire the property for $700,000 at the end of the five-year term.

There was no gain or loss on the sale as the assets were sold at their carrying value.

The future minimum lease payments together with the balance of the obligation under the capital lease is as follows:

Year ending December 31,	Amount
2004	$ 697,368
2005	697,368
2006	697,368
2007	697,368
2008	816,228
Total minimum lease payments	3,605,700
Less: amount representing interest at 6.42%	(528,854)
Present value of obligation under capital lease	3,076,846
Current portion	(514,808)
Long-term obligation under capital lease	$ 2,562,038

8. Share capital

Authorized

Unlimited number of common voting shares

Unlimited number of preferred shares issuable in one or more series

Issued and outstanding common shares:

	Number of shares	Amount
Balance December 31, 2001	9,506,686	$ 1,465,829
Issued pursuant to private placement (a)	4,897,500	2,180,000
Issued on conversion of convertible debentures (Note 6)	1,200,000	300,000
Issued pursuant to public offering (b)	3,000,000	1,200,000
Issued pursuant to exercise of brokers' warrants	22,000	9,050
Issued pursuant to exercise of flow-through warrants	1,804,158	1,262,910
Share issue costs	–	(311,461)
Tax effect of flow-through shares	–	(493,700)
Tax effect of share issuance costs	–	114,100
Balance December 31, 2002	20,430,344	$ 5,726,728
Issued pursuant to Short Form Offering Document (c)	2,200,000	1,980,000
Issued pursuant to private placement (d)	3,000,000	2,550,000
Issued pursuant to private placement (e)	2,807,200	8,000,520
Issued pursuant to Short Form Prospectus (f)	5,263,200	15,000,120
Issued on conversion of convertible promissory note	588,235	500,000
Issued on exercise of options	167,666	63,428
Issued pursuant to exercise of brokers' warrants	520,200	505,594
Issued pursuant to exercise of Series A warrants	1,443,342	1,299,008
Issued pursuant to exercise of Series B warrants	1,098,499	1,760,155
Issued pursuant to exercise of Series C warrants	1,451,500	2,335,176
Share issue costs	–	(2,343,178)
Tax effect of flow-through shares	–	(1,351,800)
Tax effect of share issuance costs	–	688,900
Black-Scholes valuation of outstanding warrants	–	(2,330,203)
Balance December 31, 2003	**38,970,186**	**$ 34,384,448**

(a) In January, 2002, the Corporation issued 2,877,500 common shares for total proceeds of $575,500 before deducting issuance costs of $4,146.

In September, 2002, the Corporation issued 250,000 units for total proceeds of $100,000. Each unit was comprised of one common share and one warrant which entitles the holder to purchase one flow-through common share at an exercise price of $0.70 per share until December 31, 2002 and $0.90 per share until December 31, 2003.

In November, 2002, the Corporation issued 1,770,000 flow-through common shares for total proceeds of $1,504,500 before deducting issuance costs of $112,281.

8. Share capital (continued)

(b) In July, 2002, the Corporation issued 3,000,000 units for total proceeds of $1,200,000 before deducting issuance costs of $194,434 and agent options to acquire 300,000 agent units at $0.40. Each unit consisted of one common share and one common share Series A purchase warrant. Each warrant entitles the holder to acquire one flow-through common share at an exercise price of $0.70 until December 31, 2002 and $0.90 until December 31, 2003. Each agent unit consists of one common share and one common share purchase warrant. Each agent warrant entitles the holder to purchase one common share at a price of $0.80 until July 11, 2004.

(c) On February 6, 2003, the Corporation issued 2,200,000 units for total proceeds of $1.98 million before deducting share issue costs of $158,400. Each unit consists of one common share and one-half of one common share Series B purchase warrant. Each full warrant will entitle the holder to acquire one flow-through common share at an exercise price of $1.40 per share until December 15, 2003. In addition to the agent's cash commission of $0.2 million, they were also granted an option to acquire 220,000 units at a price of $0.90 per agent's unit. Each agent's unit is comprised of one common share and one-half of one agent's warrant. Each full agent's warrant entitles the agent to acquire one common share at a price of $1.40 per share until December 15, 2004.

(d) On February 6, 2003, the Corporation completed a private placement of 3,000,000 units for total proceeds of $2.55 million. Each unit consists of one common share and one-half of one common share Series C purchase warrant. Each full warrant entitles the holder to acquire one common share at an exercise price of $1.40 until December 15, 2003. Share issue costs paid to the agent consisted of $0.1 million. The agents were also granted an option to acquire 150,000 agent units at a price of $0.85 per agent's unit. Each agent's unit is comprised of one common share and one-half of one agent's warrant. Each full agent's warrant entitles the agent to acquire one common share at a price of $1.40 per share until December 15, 2004.

(e) On September 9, 2003, the Corporation completed a bought-deal private placement of 2,807,200 units for total proceeds of $8.0 million before deducting share issue costs of $0.5 million. Each unit consists of one common share and one-half of one common share Series D purchase warrant. Each full warrant entitles the holder to acquire one common share at an exercise price of $3.50 until September 9, 2004. In addition to the agent's cash commission of $0.5 million, they also received 168,432 agent warrants. Each warrant entitles the holder to acquire one common share at a price of $2.85 per share until September 9, 2004.

(f) On December 31, 2003, the Corporation issued 5,263,200 units for total proceeds of $15.0 million before deducting share issue costs of $0.9 million. Each unit consists of one common share and one-half of one common share Series E purchase warrant. Each full warrant entitles the holder to acquire one common share at an exercise price of $2.85 per share until December 31, 2004.

In 2003, the Corporation renounced for income tax purposes, to the holders of the flow-through shares, exploration expenditures of $2,836,906 (2002 – $2,872,810) of which $2,485,496 (2002 – $1,453,485) had been incurred by December 31, 2003 and 2002 respectively, with the remaining $351,410 (2002 – $1,419,325) to be incurred in fiscal 2004 and fiscal 2003 respectively.

8. Share capital (continued)

The tax benefit lost of approximately $122,000 (2002 – $520,000) will be applied to share capital in 2004 and 2003 respectively.

Issued and outstanding warrants:

Warrants	Number	Amount
Series A	–	$ –
Series B	–	–
Series C	–	–
Series D	1,403,600	468,910
Series E	2,631,600	1,335,961
Agent warrants	807,232	261,135
Total	4,842,432	$ 2,066,006

Stock option plan

The Corporation has a stock option plan for its directors, officers, employees and consultants which provide options to purchase up to 3,642,334 common shares at various prices. Under the current plan, the maximum term of options is five years. Options vest and are exercisable on a cumulative basis as to one twelfth every consecutive three months after the grant date. Since the Corporation commenced trading on the Toronto Stock Exchange on July 16, 2003, the exercise price of each option equals the market price of the Corporation's common shares on the date of the grant.

The following is a continuity of stock options outstanding for which shares have been reserved:

	Number of options	Weighted average exercise price	Number exercisable at year-end	Weighted average exercise price
Balance, December 31, 2001	510,000	0.40	267,500	0.37
Granted	1,275,000	0.49		
Exercised	–	–		
Cancelled	(10,000)	0.15		
Balance, December 31, 2002	1,775,000	0.46	659,167	0.37
Granted	2,035,000	2.14		
Exercised	(167,666)	0.38		
Cancelled	–	–		
Balance, December 31, 2003	**3,642,334**	**1.40**	**1,208,169**	**0.54**

8. Share capital (continued)

The following summarizes additional information related to stock options outstanding at December 31, 2003:

	Options outstanding			Exercisable options	
Range of exercise price ($/share)	Number of options	Weighted average life (years)	Weighted average exercise price ($/share)	Number of options	Weighted average exercise price ($/share)
0.20 – 0.40	948,334	2.82	0.35	690,001	0.33
0.52 – 0.75	676,500	3.09	0.66	377,334	0.60
0.92 – 1.30	677,500	4.21	1.24	115,833	1.26
2.24 – 2.70	1,340,000	4.91	2.61	25,001	2.39
0.20 – 2.70	3,642,334	3.90	1.40	1,208,169	0.54

At December 31, 2003, 955,594 options are subject to and conditional upon the approval of the plan by the shareholders of the Corporation.

The following is a continuity of Series warrants outstanding:

($ except warrant amounts)		Number of warrants	Weighted average exercise price
Series A Warrants	Balance, December 31, 2001	–	–
	Granted	3,250,000	0.70
	Exercised	(1,804,158)	0.70
	Expired	–	–
	Balance, December 31, 2002	1,445,842	0.70
	Granted	–	–
	Exercised	(1,443,342)	0.90
	Expired	(2,500)	0.90
	Balance, December 31, 2003	–	–
Series B Warrants	Balance, December 31, 2002	–	–
	Granted	1,100,000	1.40
	Exercised	(1,098,499)	1.40
	Expired	(1,501)	1.40
	Balance, December 31, 2003	–	–
Series C Warrants	Balance, December 31, 2002	–	–
	Granted	1,500,000	1.40
	Exercised	(1,451,500)	1.40
	Expired	(48,500)	1.40
	Balance, December 31, 2003	–	–
Series D Warrants	Balance, December 31, 2002	–	–
	Granted	1,403,600	3.50
	Exercised	–	–
	Expired	–	–
	Balance, December 31, 2003	1,403,600	3.50
Series E Warrants	Balance, December 31, 2002	–	–
	Granted	2,631,600	2.85
	Exercised	–	–
	Expired	–	–
	Balance, December 31, 2003	2,631,600	2.85

8. Share capital (continued)

The following is a continuity of agent warrants outstanding:

($ except warrant amounts)	Number of warrants	Weighted average exercise price
Balance, December 31, 2001	196,500	0.44
Granted	600,000	0.40
Exercised	(22,000)	0.41
Expired	(170,500)	0.45
Balance, December 31, 2002	604,000	0.40
Granted	723,432	1.47
Exercised	(520,200)	0.77
Expired	–	–
Balance, December 31, 2003	**807,232**	**1.27**

Stock-based compensation

Effective January 1, 2002, Canadian Generally Accepted Accounting Principles require disclosure of the impact on net earnings using the fair value method for stock options granted on or after January 1, 2002 where no costs are recognized in the financial statements for the share options granted to employees or directors. If the fair value method had been used, the Corporation's net earnings and net earnings per share would approximate the following pro forma amounts:

	December 31, 2003	December 31, 2002
Compensation costs	$ 729,122	$ 43,060
Net earnings (loss):		
As reported	$ 2,824,722	$ (471,652)
Pro forma	$ 2,095,600	$ (514,712)
Net earnings (loss) per share:		
Basic		
As reported	$ 0.103	$ (0.031)
Pro forma	$ 0.076	$ (0.034)
Diluted		
As reported	$ 0.096	$ (0.031)
Pro forma	$ 0.071	$ (0.034)

During the year ended December 31, 2003, the Corporation recorded $82,865 (2002 – $nil) as compensation expense for stock options granted to non-employees.

8. Share capital (continued)

The fair value of each option granted was estimated at the date of grant using the Black-Scholes Option Pricing Model with the following weighted average assumptions for 2003:

Risk free interest rate (%)	3.53
Expected life (years)	3.00
Expected volatility (%)	55.0
Expected dividends (%)	–
Weighted average grant-date fair value ($)	0.85

Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year of 27,476,799 (2002 – 15,128,324). The diluted per share amounts are calculated using 29,398,822 (2002 – 15,128,324).

Options to purchase 1,340,000 common shares and warrants to purchase 4,203,632 common shares were outstanding during fiscal 2003 but were not included in the computation of diluted earnings per share because the options and warrants exercise prices were greater than the average market price of the common shares and, therefore, the effect would be anti-dilutive. Options to purchase 1,775,000 common shares and warrants to purchase 2,049,842 common shares were outstanding during fiscal 2002 but were not included in the computation of diluted earnings per share because they were anti-dilutive.

9. Future income taxes

(a) The components of future income tax balances are as follows:

	2003	2002
Future income tax asset		
Non-capital losses	$ 304,700	$ 422,600
Tax deductible lease payments	178,200	–
	$ 482,900	$ 422,600
Future income tax liability		
Net book value of petroleum and natural gas properties and equipment in excess of tax value	$ 4,784,300	$ 814,900
Net book value of equipment under capital lease in excess of tax deductible lease payments	267,900	–
Non-capital losses	(1,415,000)	–
Share issue costs and other	(618,600)	(158,600)
Future site restoration and abandonment costs	(38,800)	(19,100)
	$ 2,979,800	$ 637,200

9. Future income taxes (continued)

b) The provision for income taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 40.74 percent (2002 – 36.62 percent) to the earnings (loss) for the years as follows:

	2003	2002
Earnings (loss) for the year before income taxes	$ 4,444,122	$ (681,252)
Expected income tax provision	$ 1,810,535	$ (249,474)
Non-deductible crown royalties, net of Alberta Royalty Tax Credit	880,328	32,538
Resource allowance	(785,036)	12,557
Effective changes in tax rates	(286,427)	(5,221)
Provision for income taxes	$ 1,619,400	$ (209,600)

10. Related party transactions

As at December 31, 2003, the balance owing on a promissory note to a corporation controlled by a director that was included in accounts payable and accrued liabilities is $nil (2002 – $38,560). The promissory note was issued in 2000 at the exchange amount of $95,000 in exchange for petroleum and natural gas properties and has been repaid in full.

Under the terms of an administrative services contract (the "Administrative Services Contract") dated January 1, 2003, between the Corporation and a corporation controlled by a director of the Corporation, the Corporation incurred management fees of $99,000 (2002 – $126,000) for the provision of offices, office equipment, administration, management and support personnel. There is no term to the Administrative Services Contract but it may be terminated by the Corporation at any time upon written notice and the payment of 12 months administration fees. The Administrative Services Contract was terminated in December, 2003 and termination fees of $99,000 were paid. The transactions were measured at the exchange amount and were in the normal course of operations. As at December 31, 2003, the amount owed under the Administrative Services Contract and included in accounts payable and accrued liabilities was $nil (2002 – $1,564).

Accounts payable include $nil (2002 – $83,252) owed to a shareholder which provided administration services to the Corporation in prior years. There have been no charges in 2003 (2002 – $nil) from the shareholder. The shareholder has certain directors that are directors of the Corporation.

In exchange for a promissory note receivable, in December, 2001 the Corporation loaned $25,000 to a person who became a director and officer of the Corporation in January, 2002. The promissory note receivable was non-interest bearing, and was due on or before April 1, 2002. On April 1, 2002 the promissory note receivable of $25,000 was repaid in full.

In exchange for a promissory note receivable, in May, 2002, the Corporation loaned $15,000 to an officer of the Corporation. The promissory note receivable is non-interest bearing, and is due in three equal annual installments on or before May 15, 2003, 2004, 2005. At December 31, 2003, the balance outstanding on the promissory note receivable is $10,000 (2002 – $15,000).

11. Financial instruments

Fair value of financial instruments

The carrying value of cash and cash equivalents, accounts receivable, share subscriptions receivable, promissory notes receivable, and accounts payable and accrued liabilities approximates their fair values due to the immediate or short-term maturity of these instruments.

The carrying value of the obligation under capital lease approximates the fair value as the interest rates are consistent with the current rates offered to the Corporation for other debt with similar terms.

The convertible promissory note due to shareholder has no quoted market price as it is not traded in an active liquid market. Further, there is no readily available quoted market price for the same or similar issues subject to similar risks and maturities. Therefore, it is not practicable to determine the fair value with sufficient reliability. Refer to Note 5 for the principal characteristics of this financial instrument.

Foreign currency risk management

The Corporation is exposed to foreign currency fluctuations as crude oil prices received are referenced to U.S. dollar denominated prices.

Interest rate risk

The Corporation is exposed to a floating interest rate on its bank borrowings.

Credit risk management

The Corporation's accounts receivable are with customers and joint-venture partners in the petroleum and natural gas industry and are subject to normal credit risks. The Corporation sells substantially all of its production to two large credit-worthy purchasers under normal industry sale and payment terms. As a result, the Corporation views the credit risk on these items as minimal. Purchasers of the Corporation's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment. Amounts receivable from joint-venture partners included in accounts receivable are recoverable from production and, accordingly, the Corporation views credit risks on these amounts as minimal.

Commodity risk management

The Corporation is party to certain off-balance sheet derivative financial instruments which consist of crude oil swap contracts. The Corporation enters into these contracts for the purpose of protecting its future earnings and cash flow from operations from the volatility of crude oil prices. The swap contracts reduce the fluctuations in petroleum revenues by locking in fixed forward-prices on a portion of the Corporation's crude oil production.

The Corporation has entered into short-term arrangements for crude oil swap contracts. For the year ended December 31, 2003, the Corporation realized a net loss of $217,407 (2002 – $nil) on its crude oil price risk management.

11. Financial instruments (continued)

Crude oil contracts outstanding in respect to financial instruments as at December 31, 2003 were as follows:

Contract	Volume	Commodity	Pricing point	Fixed price	Contract term
Fwd Sale	800 bbls/day	WCB Oil	WTI	U.S.$28.66/bbl	Jan 01/04 – June 30/04
			WCB		
			Differential	U.S.$7.50/bbl	
Fwd Sale[1]	800 bbls/day	WCB Oil	WTI	U.S.$31.25/bbl	July 1/04 – Dec. 31/04
			WCB		
			Differential	U.S.$8.15/bbl	
Fwd Sale[1]	500 bbls/day	WCB Oil	WTI	Cdn$44.35/bbl	April 1/04 – Dec. 31/04

[1]Transactions entered into after December 31, 2003 are not reflected in estimated fair market values below.

At December 31, 2003 the estimated fair value of the above financial instrument transactions was $451,616 based on a Canadian dollar exchange rate of $1.2924 per U.S. dollar.

The above estimated fair value is based on the market value of these instruments as at year-end and represent the amounts the Corporation would have paid to terminate the contracts at year-end.

12. Commitments

a) The Corporation has operating lease commitments for office space and various equipment. The future minimum lease payments for the next five years are as follows:

2004	$ 245,176
2005	93,440
2006	93,440
2007	7,787
2008	–
	$ 439,843

b) Pursuant to the issuance of Series A and Series B flow-through warrants (Note 8), and the subsequent exercise of these warrants in 2003, the Corporation received gross proceeds of $2,836,906. The Corporation renounced $1,299,008 to Series A warrant holders effective December 31, 2003 and renounced $1,537,898 to Series B warrant holders effective December 31, 2003. The Corporation has incurred $2,485,496 to December 31, 2003 and has until 2005 to expend $351,410 on qualified expenditures.

13. Subsequent event

On January 14, 2004, the Corporation entered into a joint venture agreement with another oil and gas company, pursuant to which the Corporation will contribute funds for purposes of acquisition, exploration and development of petroleum properties. Upon signing of the agreement, the Corporation immediately contributed $1.5 million to a trust account for purposes of land acquisitions. An additional $1.8 million shall be contributed at a later date once 80 percent of the original deposit has been expended on land acquisitions. Any funds not expended on land acquisitions will be returned to the Corporation.

All expenditures are subject to approval of an authorization of expenditure by both parties before funds are released from the trust account. Subsequent to successful acquisition of lands, amounting to $3 million, the other party will incur expenditures for drilling, completion, equipping and operating costs to a total of $3 million. Upon completion of these expenditures by the other party, both parties will complete an equalization of costs requiring payment or receipt of funds to ensure both parties incurred 50 percent of the total cost.

The Corporation will then have a 40 percent participating interest in subsequent operations of this joint venture.

14. Supplemental cash flow information

The Corporation has made cash payments of interest of $300,429 (2002 – $41,802) and cash payments for income taxes of $nil (2002 – $nil).

Changes in non-cash working capital:

	2003	2002
Accounts receivable	$ (4,080,796)	$ (276,728)
Accounts payable and accrued liabilities	18,500,212	591,380
	14,419,416	314,652
Less: change in non-cash working capital related to investing	15,333,398	473,103
Change in non-cash working capital related to operating activities	$ (913,982)	$ (158,451)

15. Comparative figures

Certain comparative figures have been reclassified to conform with the presentation adopted in the current year.

Corporate Information

Directors

Michael R. Binnion
Calgary, Alberta
Chairman[1]

Robert D. Bowman
Calgary, Alberta
President and Chief Executive Officer

Robert G. MacCuish[1]
Calgary, Alberta

David G. Mallory
Calgary, Alberta
Chief Financial Officer and Corporate Secretary

Peder N. Paus[1]
Oslo, Norway

Jed M. Wood[1]
Red Deer, Alberta

[1] *Member of Audit, Compensation, Governance and Reserves Committees*

Officers

Robert D. Bowman
President and Chief Executive Officer

David G. Mallory
Chief Financial Officer and Corporate Secretary

Paul J. Poscente
Vice President, Exploration

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Toronto Stock Exchange
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